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Enhanced Oil Recovery

# Polymer injectivity – scaling viscosity from lab to field

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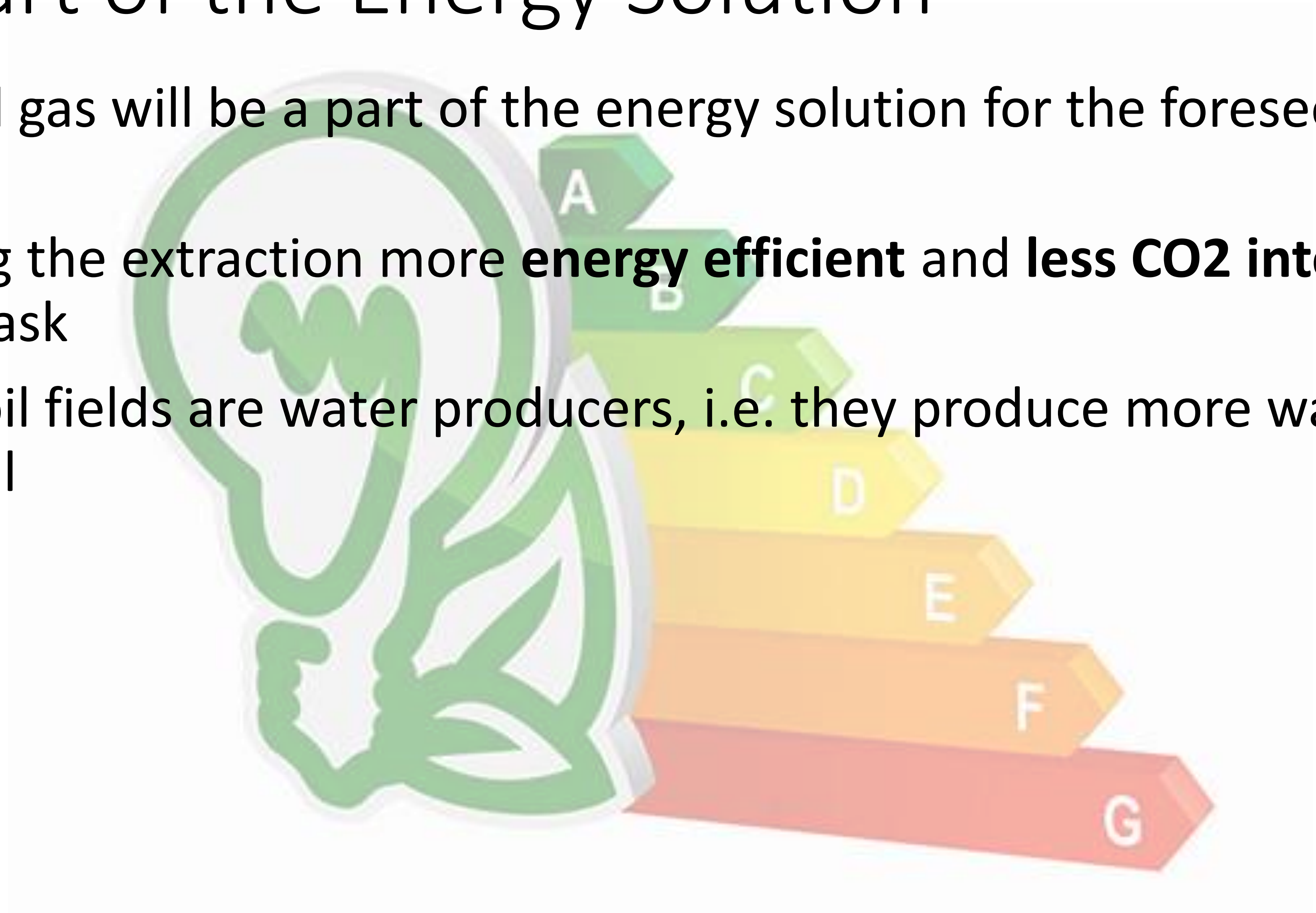
# Outline

- Polymer Flooding in a Low Carbon Future
- Challenges in Polymer Flooding
- Polymer Injectivity Criteria
- Polymer Injectivity Results
- Implementation of Lab Data in Polymer Injectivity Well Test
- Summary

# Polymer Flooding
# – a Part of the Energy Solution

- Oil and gas will be a part of the energy solution for the foreseeable future
- Making the extraction more **energy efficient** and **less CO2 intensive** is a key task
- Most oil fields are water producers, i.e. they produce more water than oil

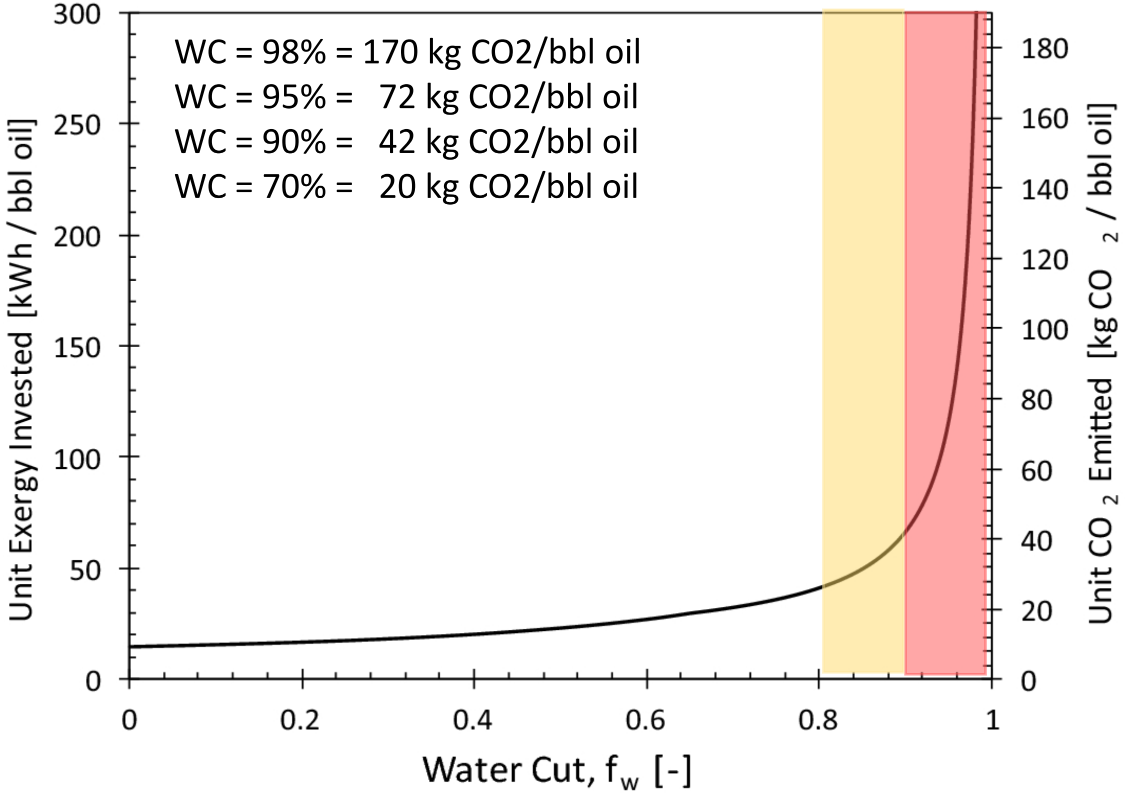


# Polymer Flooding in a Low Carbon Future

- Water handling is the dominant energy consumer in oil production
- Water injection, production, lift, separation
- **60-80 % of the exergy invested is related to water handling**

- Reducing water cut is the most beneficial action in order to reduce CO2 emissions

- Polymer flooding improves sweep and reduces WC
- PF can lead to more than 50% reduction in CO2 emissions per bbl oil produced
- Cheap solution – PF will give a return on invested money



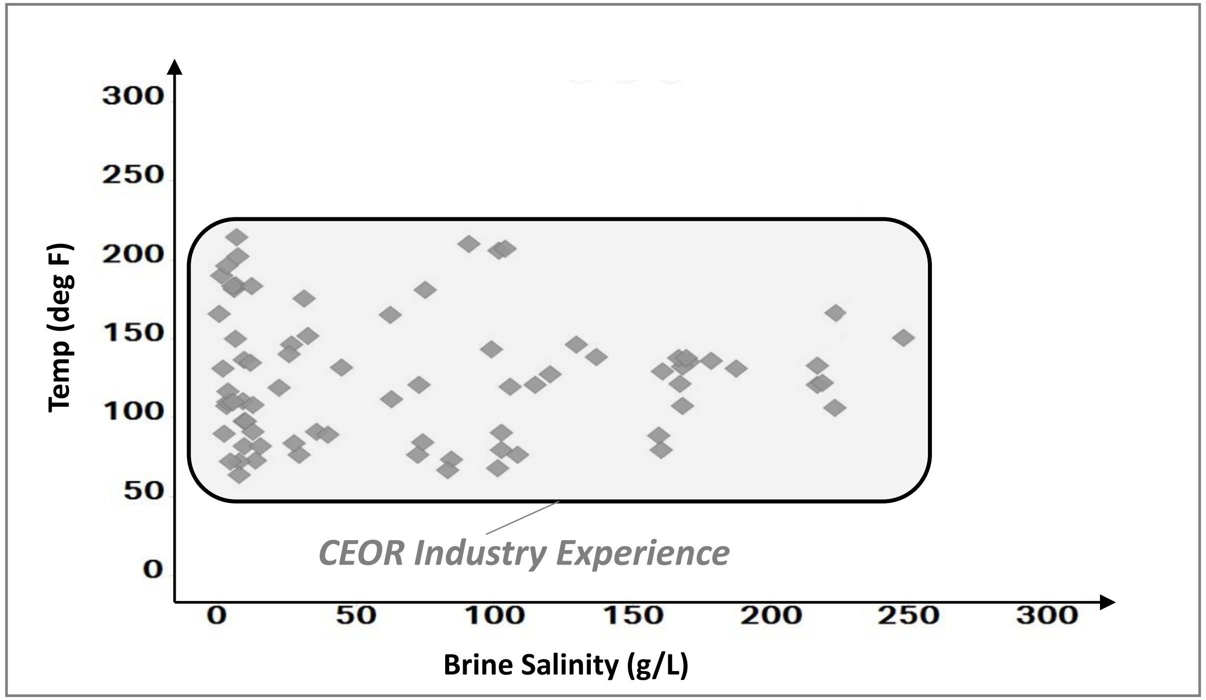

$$e_{CO_2,WF} \approx a w_{UF} = \frac{a}{1-f_w}$$

Farajzadeh, R., Kahrobaei, S., Eftekhari, A.A. *et al. Sci Rep* **11**, 829 (2021). https://doi.org/10.1038/s41598-020-80369-z

# Challenges for polymer flooding

- Proven in (homogeneous) sandstone, up to 90 °C, > 100 mD, sea water (Mangala, Marmul, Captain, Peregrino, …)

- Challenges
  - HTHS
  - Low permeability
  - Heterogeneous
  - Carbonates



# Challenges for polymer flooding

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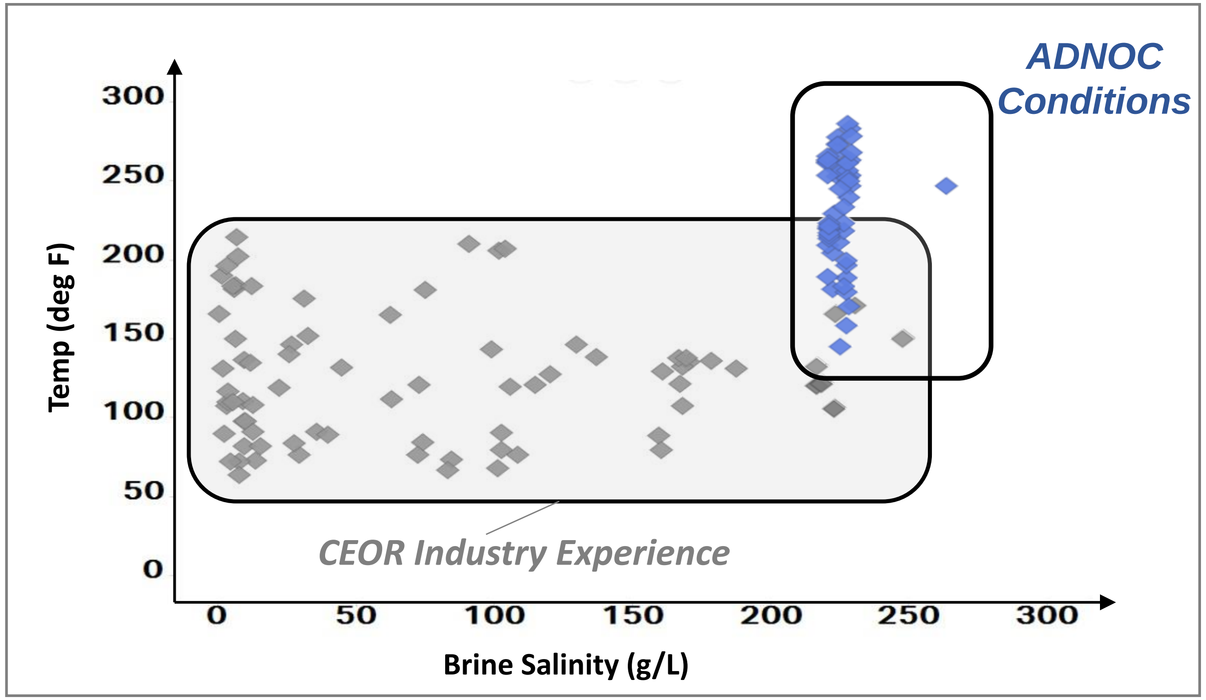



Needed to stretch the limits of technology

New polymer was qualified through an international cooperation

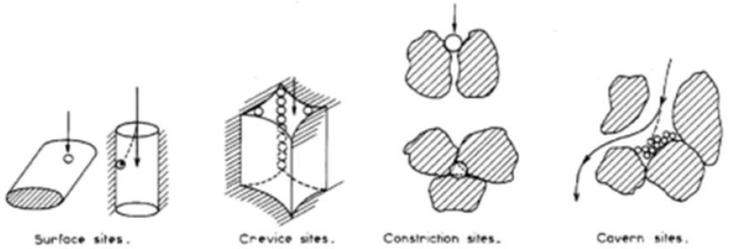
# Polymer Injectivity

- Critical parameter
- Voidage replacement – maintain injection
- Increased viscosity
- Non-Newtonian (Shear thinning, thickening)
- Fractures
- Radial flow
- Well clean up
- Sand consolidation

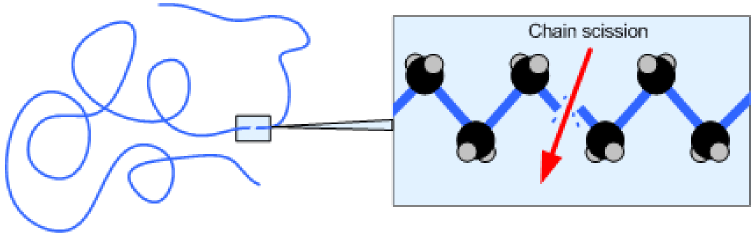
# Polymer Injectivity – Evaluation Criteria

In laboratory studies, polymer injectivity is evaluated primarily by 3 factors:

- Propagation and filtration (pressure stability)
- Formation damage (permeability reduction, RRF)
- Mechanical degradation of the polymer (viscosity loss)

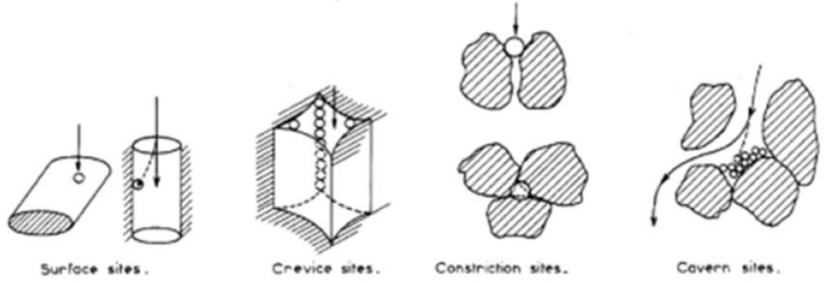


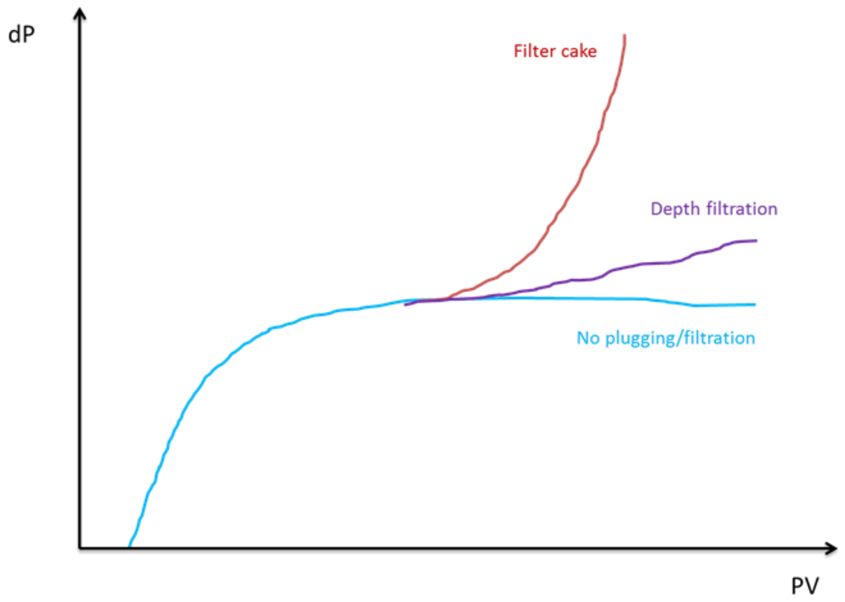

from Herzig et al. 1970



# Propagation and Filtration

- **Filter cake formation** observed as a continuous increase of differential pressure at an exponential rate.
- Caused by accumulation of polymer at the sandface:
  - Large polymer size relative to the pore size and/or
  - Poor homogeneity of the polymer solution
  - Debris/residuals in the polymer solution
- Leads to a gel-like residue on the surface of the core, eventually blocking the passage of polymer through the core, i.e. plugging.
- **Depth filtration** observed as a steady increase in dP
  - Surface interaction of smaller particles
  - Blocking of pore throats by intermediate and large particles

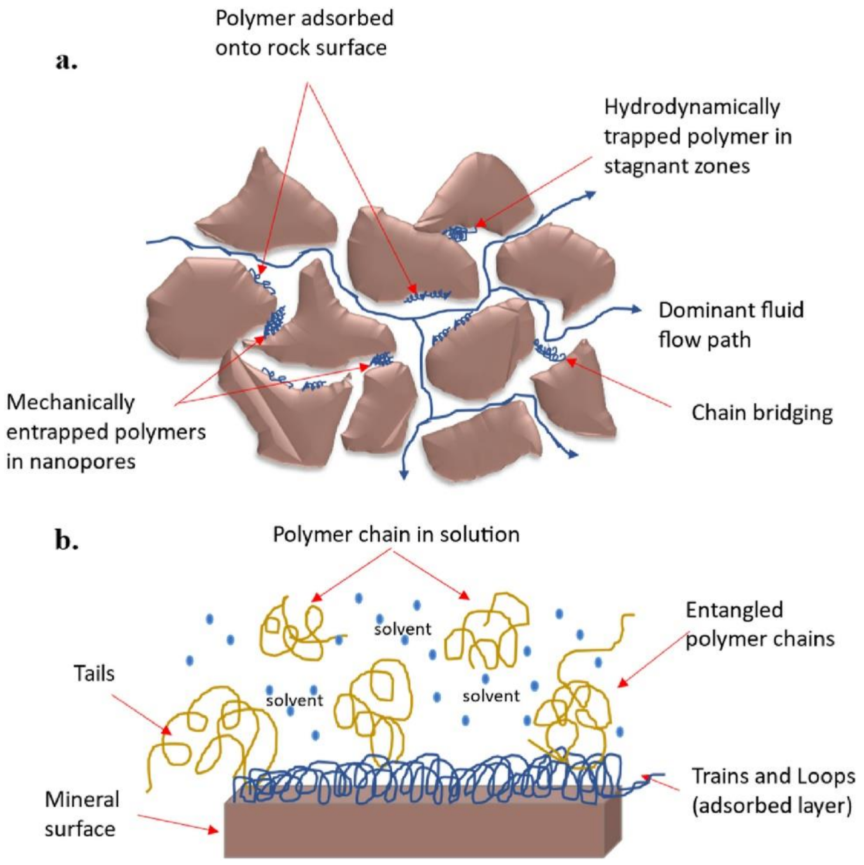



Schematic representation of pressure development in the case of filter cake formation and in-depth filtration for a polymer injectivity experiment.

# Formation damage - RRF

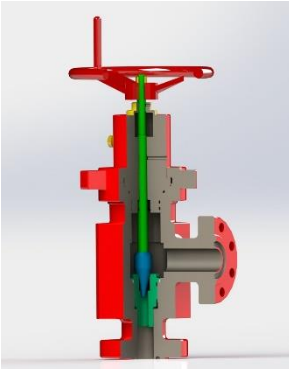
- Permeability is reduced as a consequence of polymer adsorption and entrapment
- Residual Resistance Factor, RRF, i.e. ratio of permeability prior to and after polymer injection. $RRF = K_{w,pri}/K_{w,post}$
- Generally perceived as irreversible.
- Unlike filtration, RRF reaches a plateau and constant value once adsorption is satisfied, typically after 1 – 5 PV

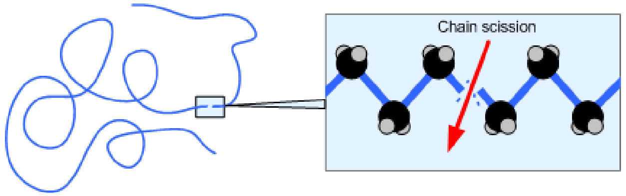


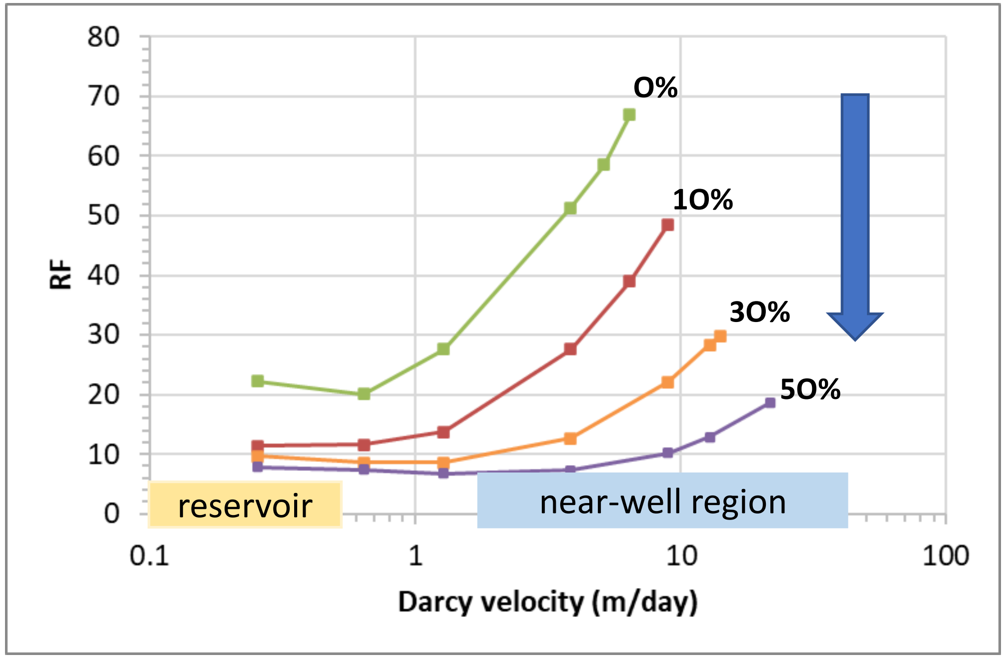

Ekanem et al., JCIS Open, 2021, https://doi.org/10.1016/j.jciso.2021.100026

# Mechanical Degradation

- Viscosity loss due to mechanical degradation may lead to low viscosity in the reservoir
- Degradation may occur from e.g. choke passage, screen perforation, entrance to porous media.
- Controlled pre-degradation may reduce uncertainty and improve injectivity
- In lab studies, flow velocity has to be scaled according to well properties and permeability range

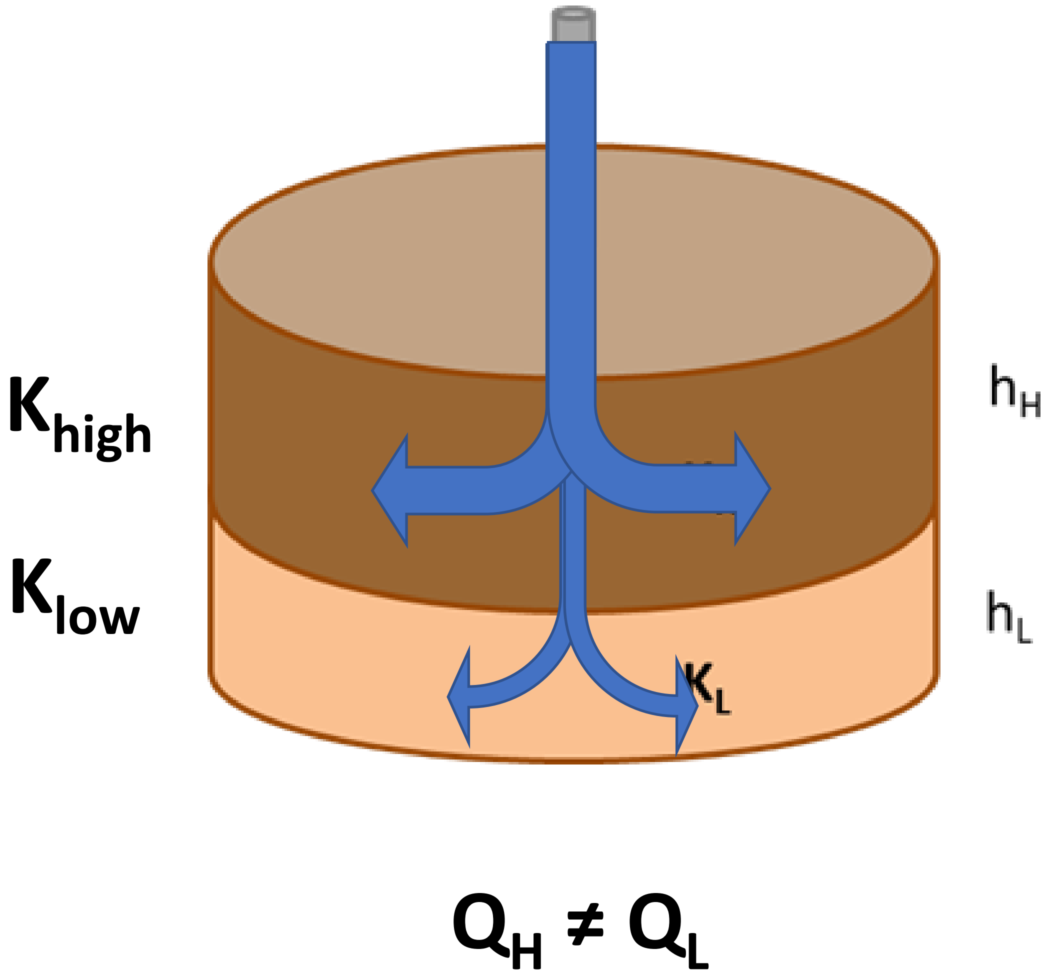




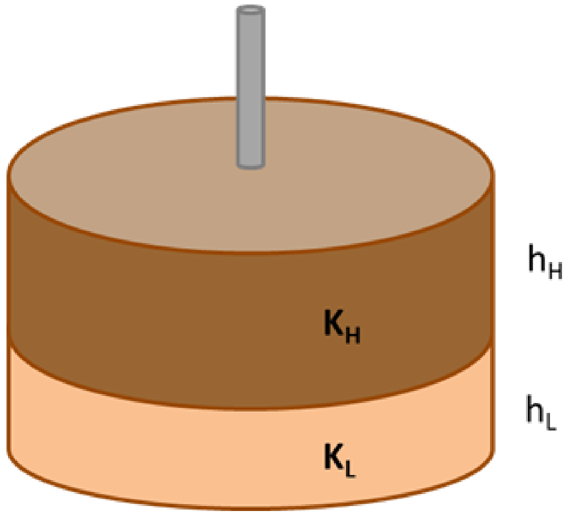
# Scaling field to lab flow rates

- In many cases in the literature, flow rates are scaled directly from the flow velocity in at the sandface of given permeability
- However, in a multi-layered well, the flux will vary with permeability
- It will therefore be misleading to conduct injection experiments with the same rate in core with high and low permeability.



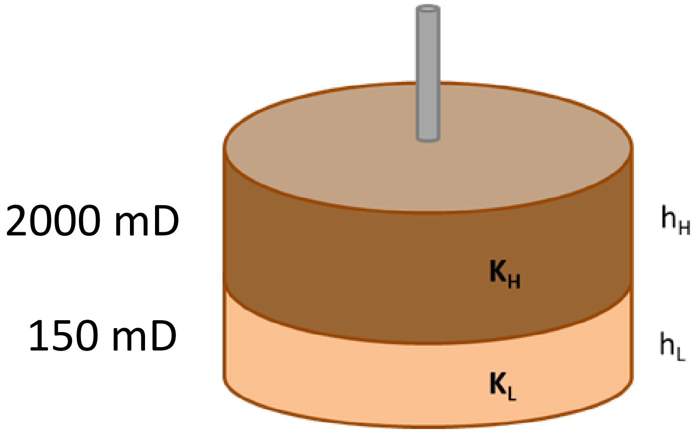
# Scaling field to lab flow rates

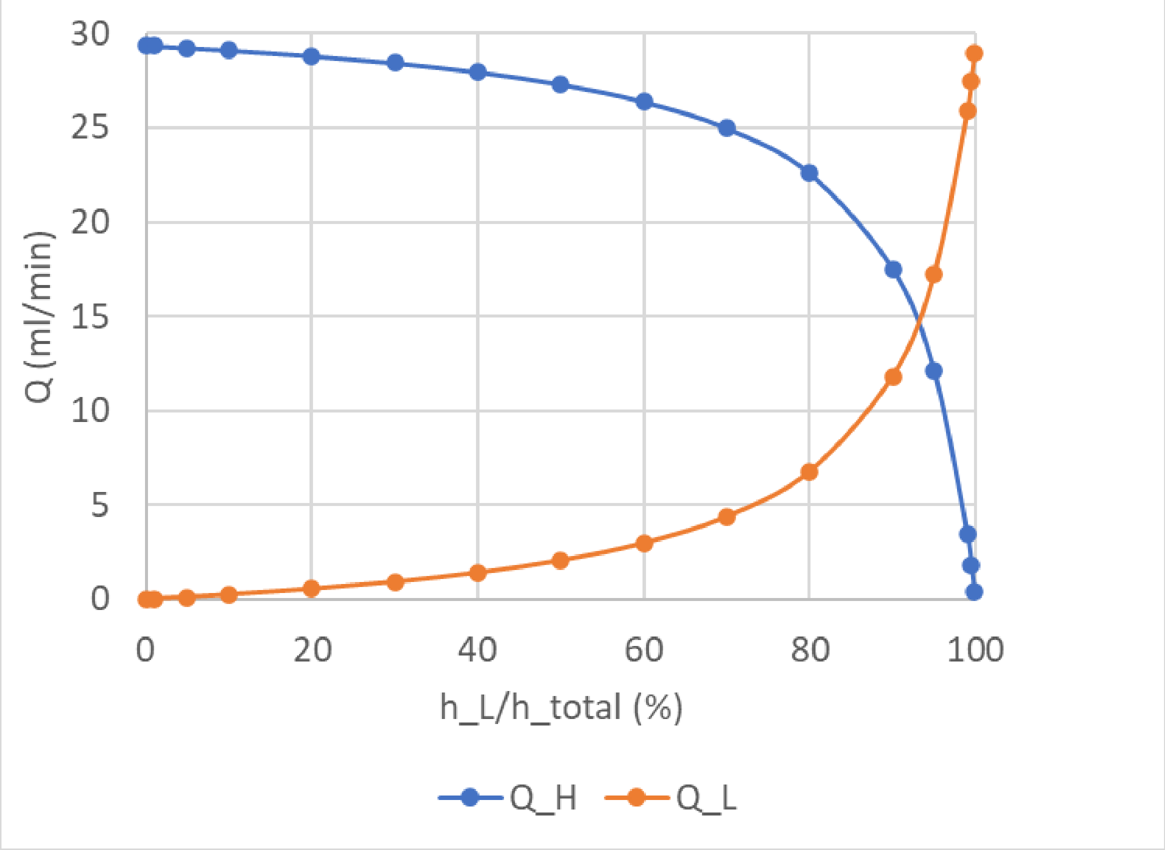
- A two-layer simplified model is used to represent the high and low target zones.
- Flow velocities are matched from the simple:
  - $u_{well} = u_{core}$
  - $Q_{well}/A_{well} = Q_{core}/A_{core}$
- The flow velocity in a laboratory core experiment cannot be used directly because the injection well does not have constant permeability
  - $Q_{Tot} = Q_H + Q_L$
  - $h_{Tot} = h_H + h_L$
  - $Q_H/Q_L = (K_H*h_H) / (K_L*h_L)$
  - $Q_L = Q_{tot} / [1+(K_H*h_H/K_L*h_L)]$
  - $Q_{L,core} = [Q_{well} *A_{core} /A_{well}]/ [1+(K_H*h_H/K_L*h_L)]$



# Scaling lab injection rates

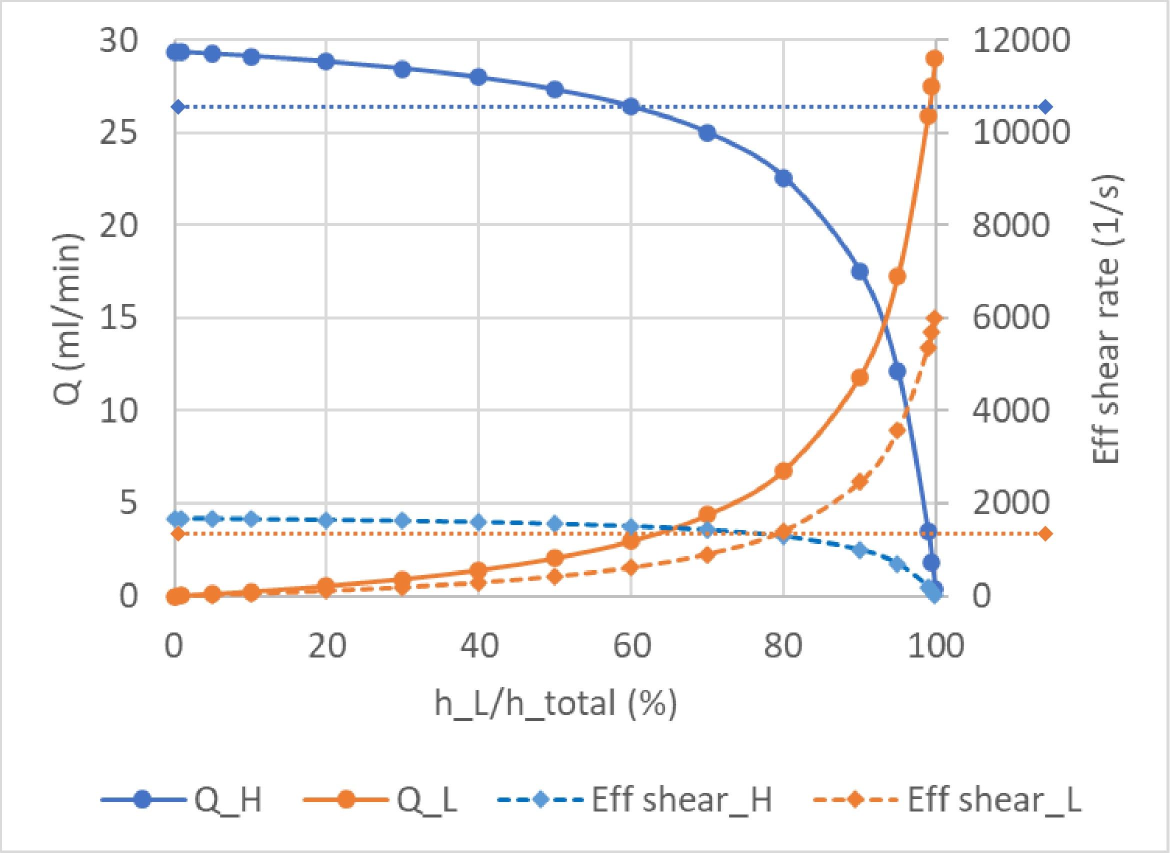
| Parameter | Well (field units) | | Well (SI units) | Core (SI units) | unit |
|---|---|---|---|---|---|
| Well/Core injection rate | 2000 | bbl/day | 318 | TBD | m3/day |
| Well/Surface diameter | 7 | Inch | 0.1778 | 0.038 | m |
| Well completion length (zone thickness) | 50 | ft | 15.24 | - | m |
| Porosity | 0.28 | frac. | 0.28 | 0.28 | frac. |
| Injection surface area (A=2πrh) | | | 8.5 | 0.00113 | m2 |
| Darcy velocity (υ=Q/A) | | | 37.4 | 37.4 | m/day |

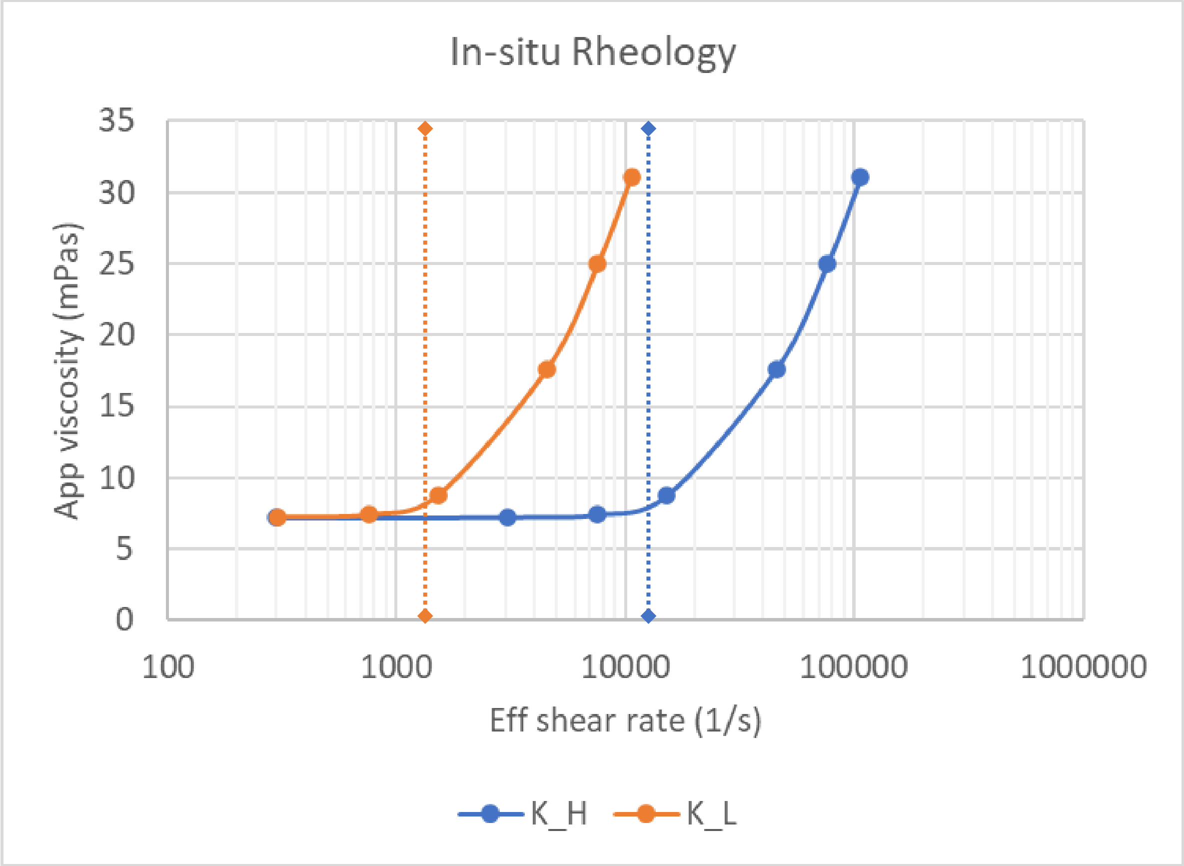


# Scaling lab injection rates

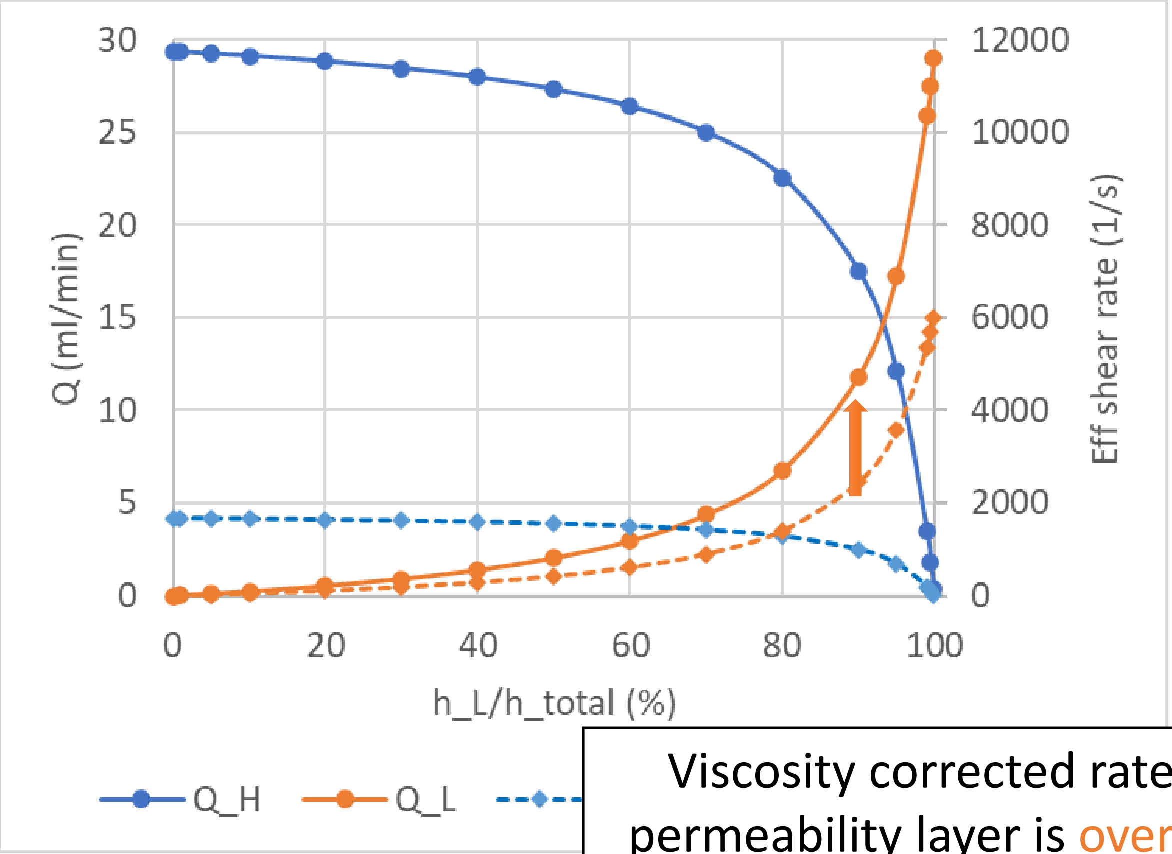
$$\Delta P = \frac{Q}{A}\frac{\mu(\dot{\gamma})L}{K} \qquad \dot{\gamma}_{eff} = \frac{4\alpha u}{\sqrt{8K\phi}}$$

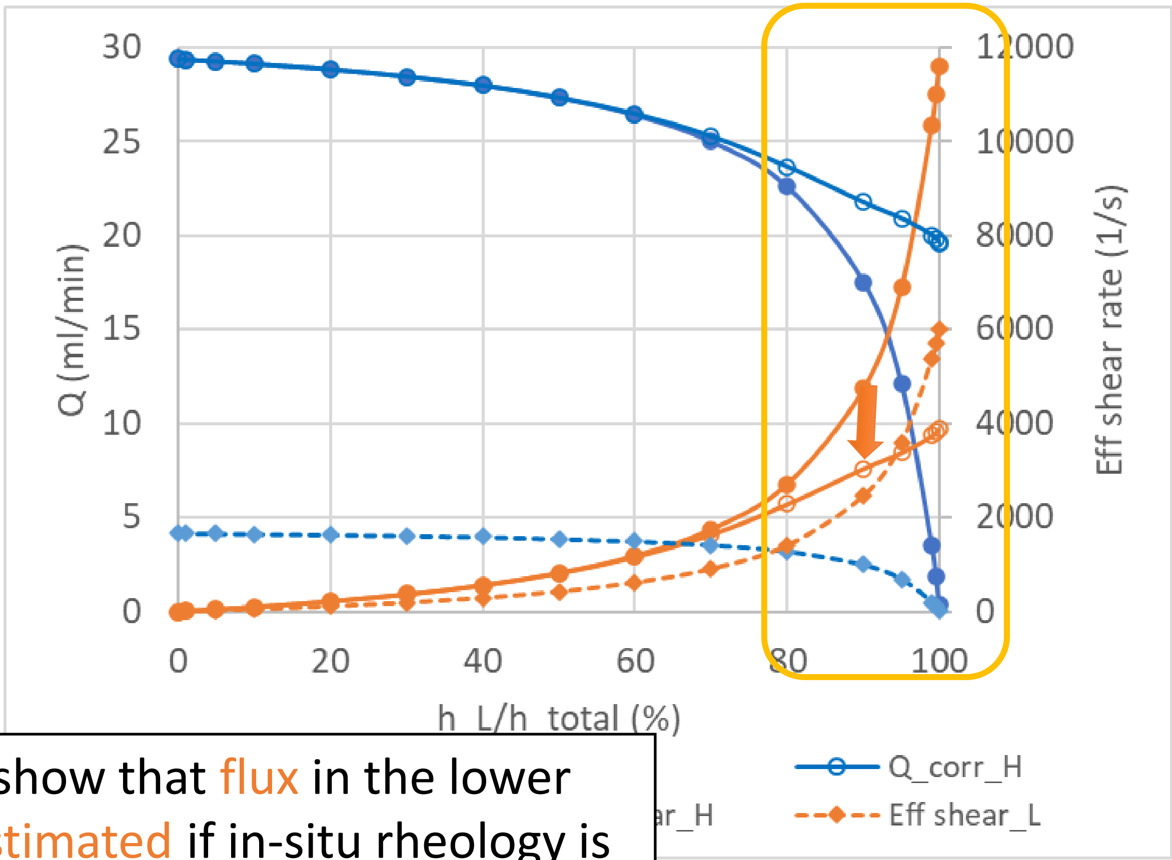



Can estimate boundaries for when elongational effects become important for injectivity

# Scaling lab injection rates




Viscosity corrected rates show that flux in the lower permeability layer is overestimated if in-situ rheology is not taken into account. Applying bulk rheology would imply that injectivity was higher (wrongly)

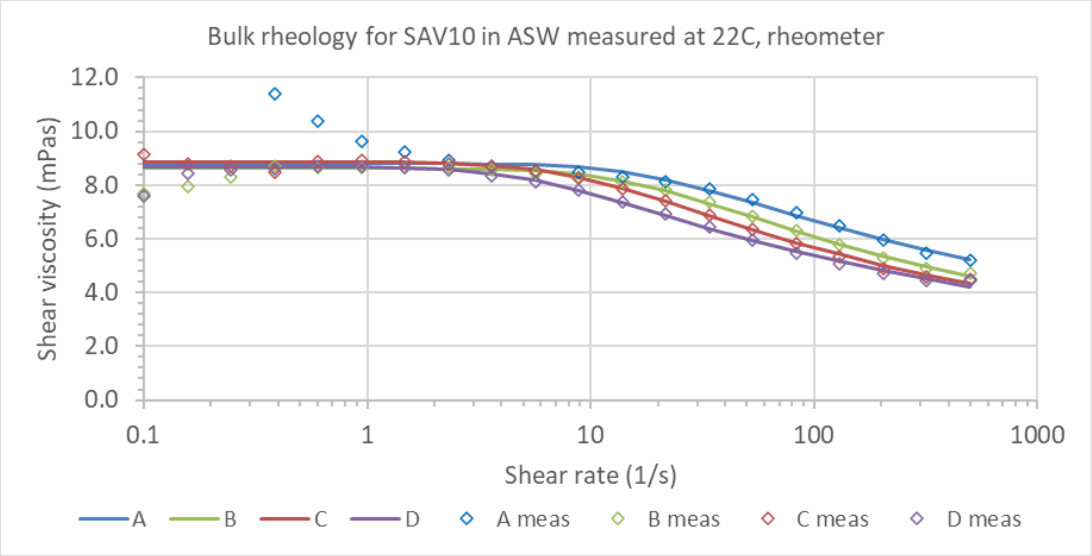
# Polymer Injectivity – Influence of pre-degradation

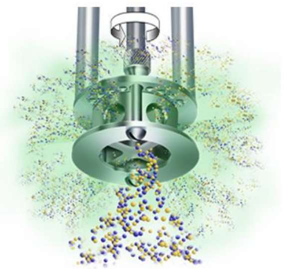
How does pre-degradation influence injectivity?

- Pre-sheared to 50, 70, 90 and 100% of initial viscosity using Silverson homogenizer
- Polymer SAV10 in high salinity brine (240 000 ppm TDS)

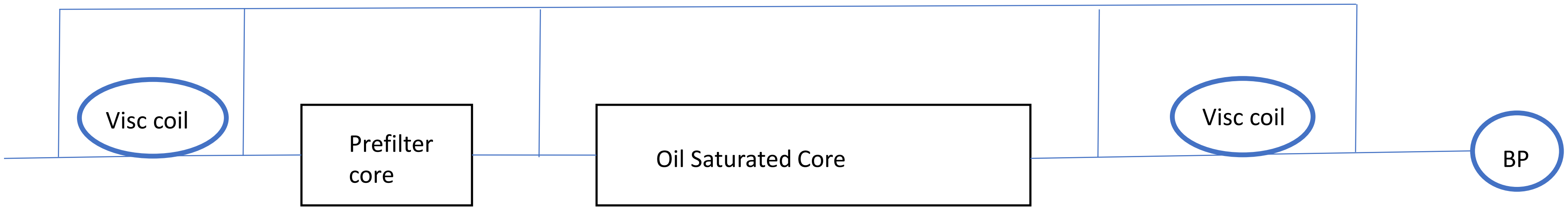
- Different degree of pre-degradation leads to difference in Mw for polymers A-D
- Different Mw gives different rheology curves for polymers A-D

| | Pre-degradation (%) | Viscosity at 2000 ppm (mPas) | Applied Conc (ppm) | Viscosity at diluted concentration (ppm, 10 1/s 22C) |
|---|---|---|---|---|
| A | 50 | 4.71 | 2915 | 8.47 |
| B | 30 | 6.54 | 2337 | 8.46 |
| C | 10 | 8.37 | 2000 | 8.37 |
| D | 0 | 9.35 | 1874 | 8.42 |



# Polymer Injectivity – Influence of pre-degradation

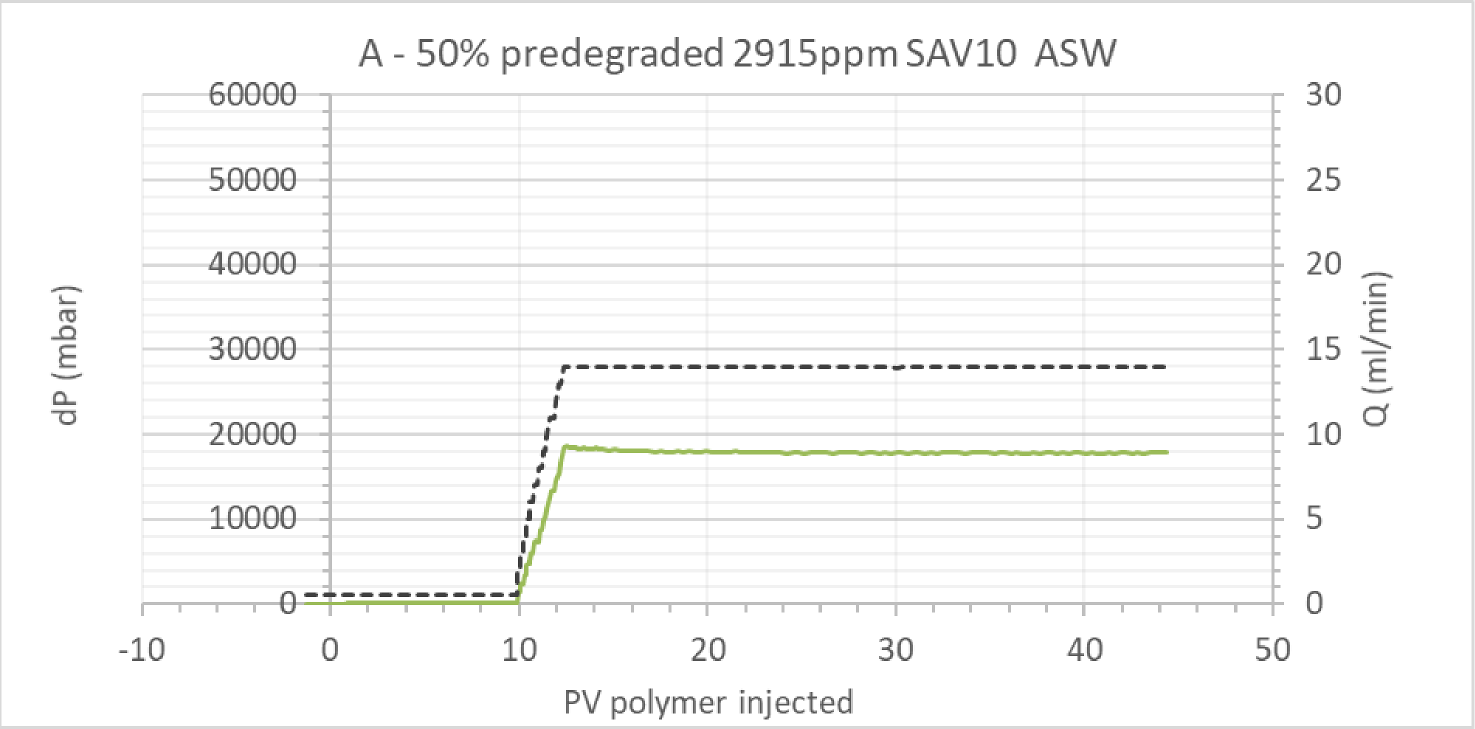


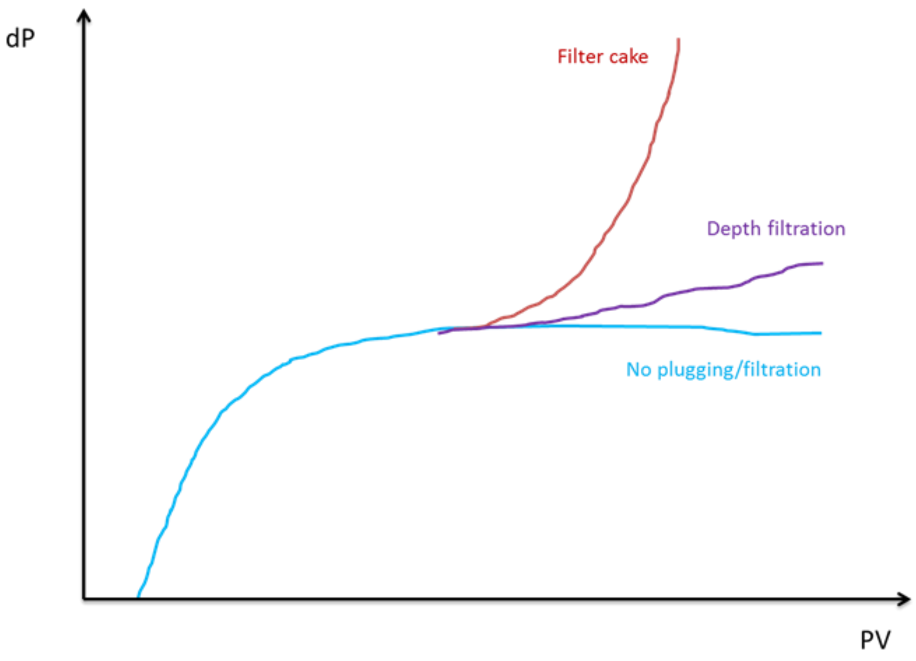

**Pre-core L= 5 cm,**
**Bentheimer Kw = 0.9 D**

| ZK34-22 | Swi=0.12 | Sw=0.805/0.864 |
|---|---|---|
| L = 6.55 cm | Kw,abs=147 mD | Kw,Sorw= 66 mD |

# Polymer Injectivity – 50% pre-degradation

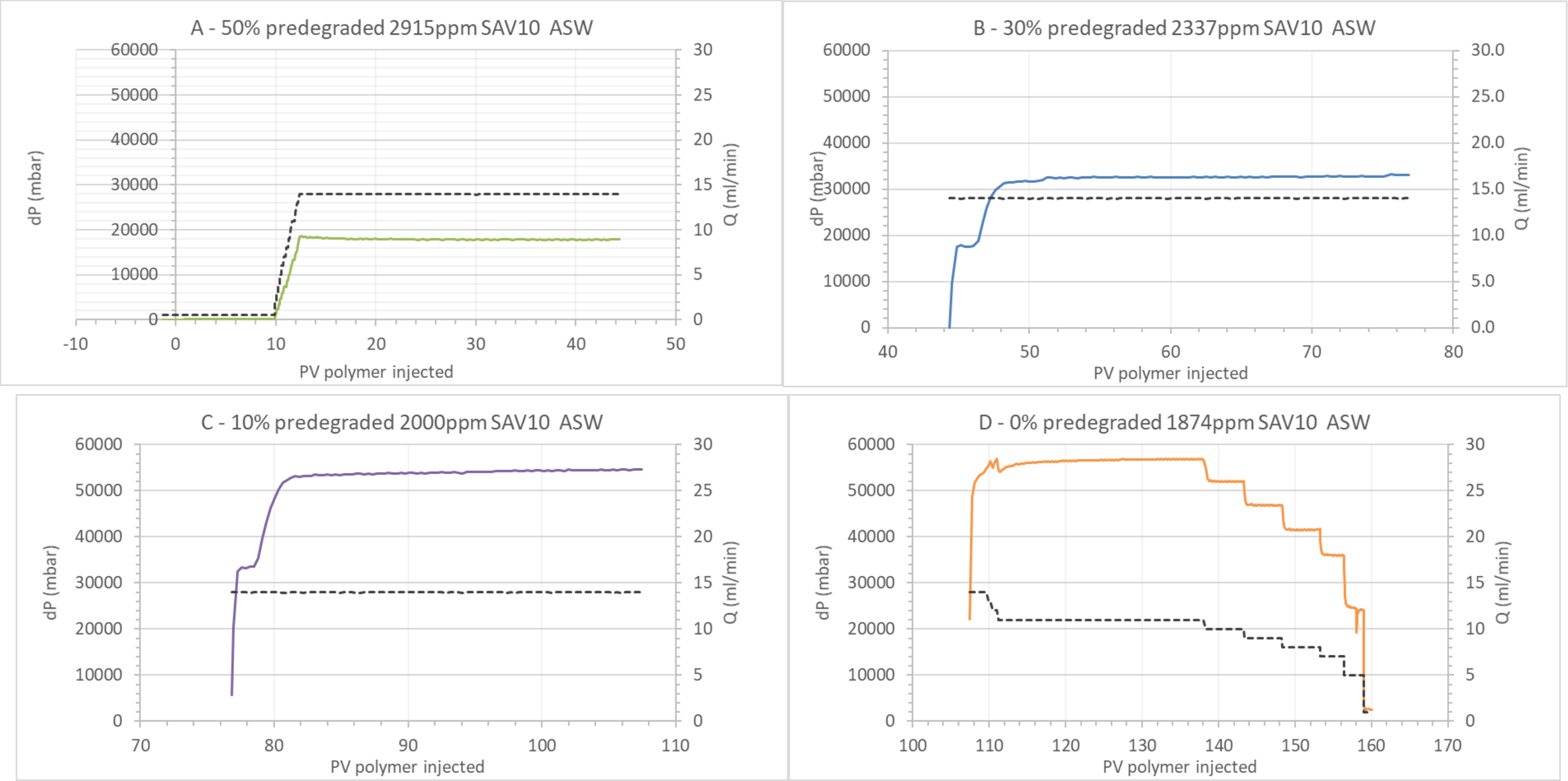
- Good injectivity as shown by stable pressure over large PV injected
- No sign of filter cake formation or depth filtration
- Very good result for low permeability and heterogeneous carbonate rock



# Polymer Injectivity - pre-degradation

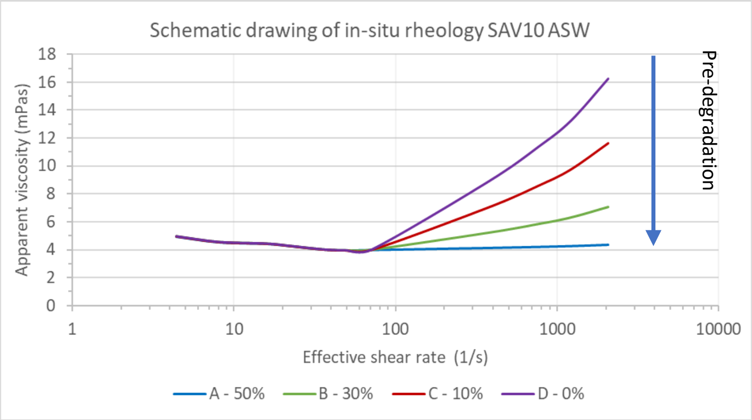
- Good injectivity for all solutions as shown by stable pressure over numerous PV injected
- Injection pressure inversely proportional to % pre-degradation

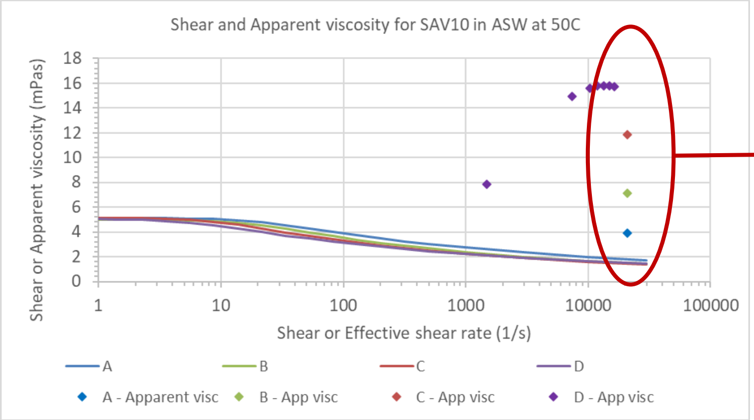


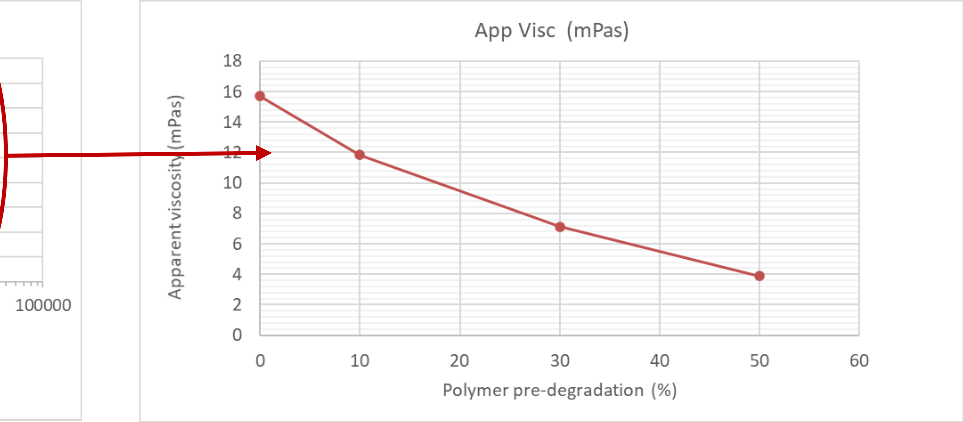

| | A | B | C | D |
|---|---|---|---|---|
| Kw,abs (mD) | 147 | | | |
| Kw,Sorw (mD) | 66 | | | |
| Kw,end (mD) | 30 | 30 | 30 | 30 |
| RF at Vd = 18 m/day | 14 | 26 | 43 | 56* |
| RF/RRF | 6 | 12 | 20 | 25 |
| RF/Qmax | 14/14 | 26/14 | 43/14 | 57/11 |
| RRF | 2.2 | 2.2 | 2.2 | 2.2 |

# Influence of pre-degradation on injectivity

- The apparent viscosity at the highest rate, equivalent to an effective shear rate of 21 000 1/s, is plotted as function of pre-degradation below
- The apparent viscosity is strongly decreasing for pre-degraded solutions. This is due to the reduced Mw of the polymer.
- The lower average Mw leads to lower shear thickening of the polymer as illustrated in the graph lower left.



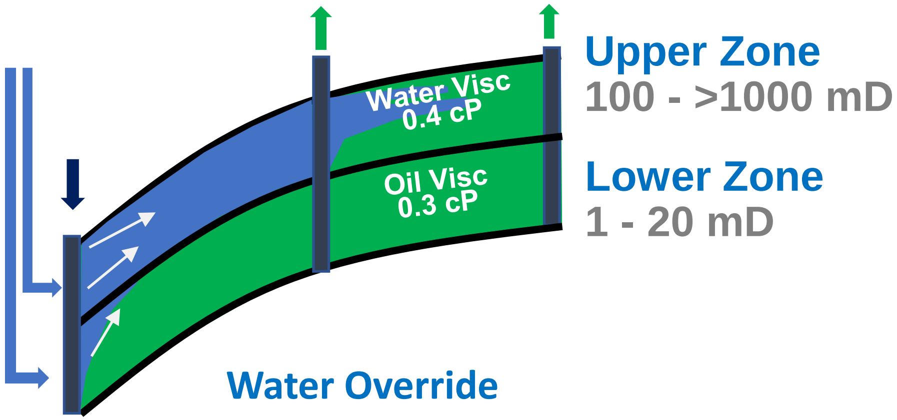

Same bulk viscosity injected, different pre-degradation

=> Large difference in injection pressure

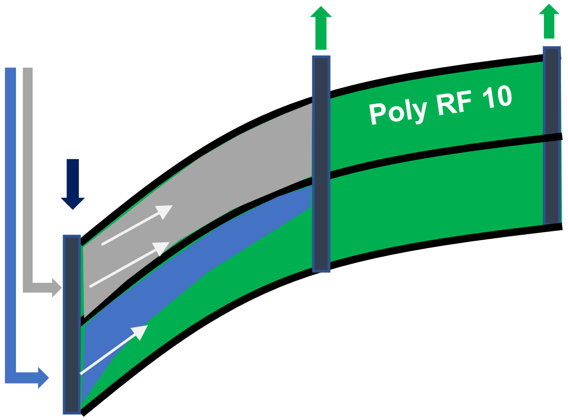
# Polymer Injectivity – Influence of pre-degradation

- No indication of plugging or in-depth filtration were observed for the reservoir rock
- The permeability reduction, RRF, of the core after polymer flood is 2.2 which is relatively low for carbonate rock at high salinity.
- Negligible mechanical degradation, only a 10% viscosity reduction at highest injection rate for the non-degraded solution. Pre-degraded solutions showed no mechanical degradation.
- Non-degraded polymer show 4 x the injection pressure of 50% pre-degraded polymer. To compensate for the viscosity loss of the pre-degraded polymer, a concentration increase of 60% is required
- The results are not directly transferable to field conditions. Near-well conditions may dominate and detailed simulations studies are required.

# Modeling Polymer Injectivity - PIT

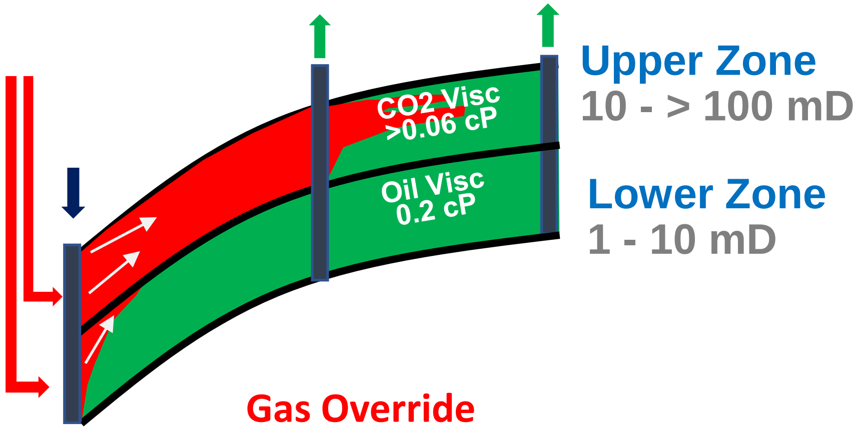



SIWAP

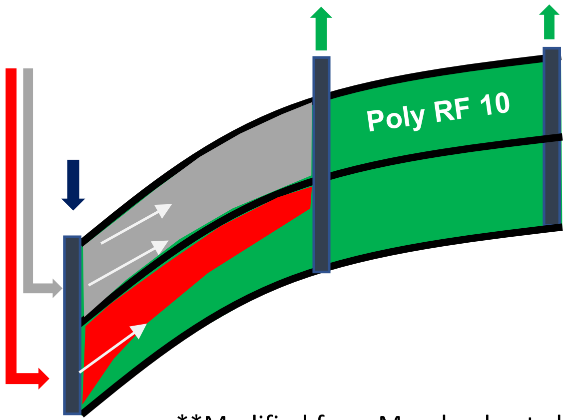



Pressure barrier due to polymer injection, keep Water or ($CO_2$) in the lower zone and improve sweep efficiency and recover by-passed oil.

**Polymer RF Target ± 10.**




SIMGAP

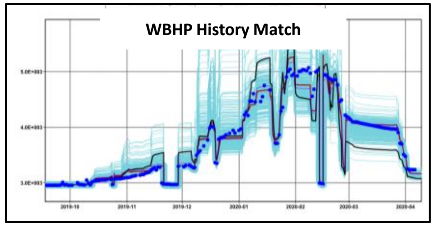


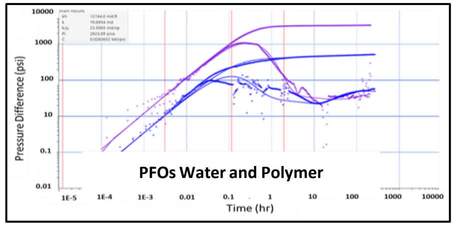

**Modified from Masalmeh, et al (2014)

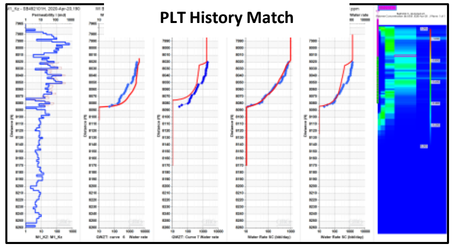
**Polymer injection series**

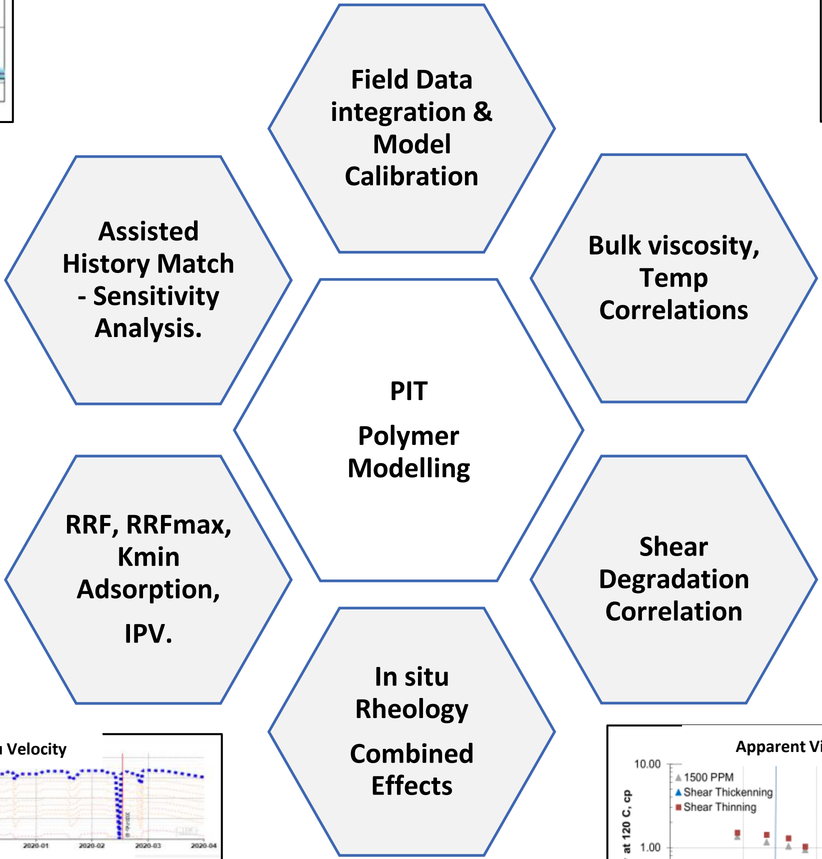
| | Pre-degradation (%) |
|---|---|
| A | 50 |
| B | 30 |
| C | 10 |
| D | 0 |

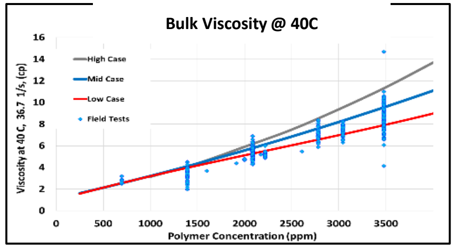
# Modeling Polymer Injectivity - PIT

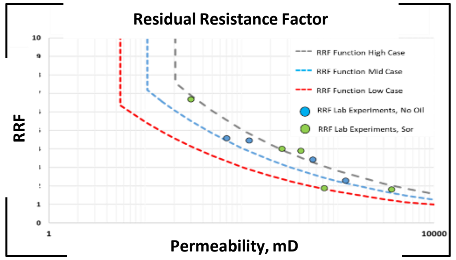


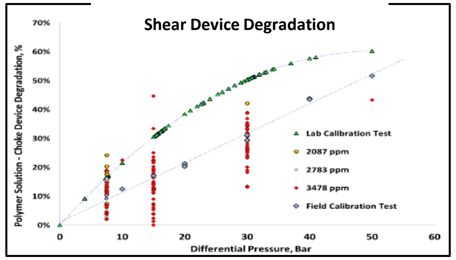



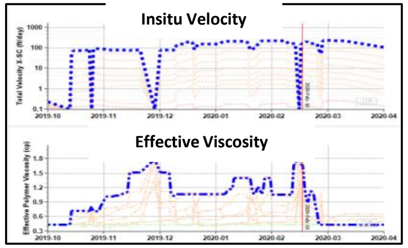



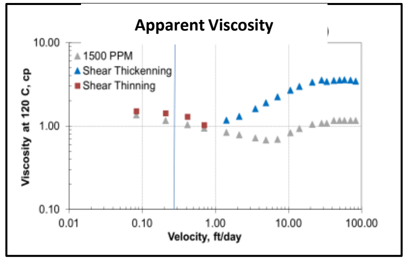



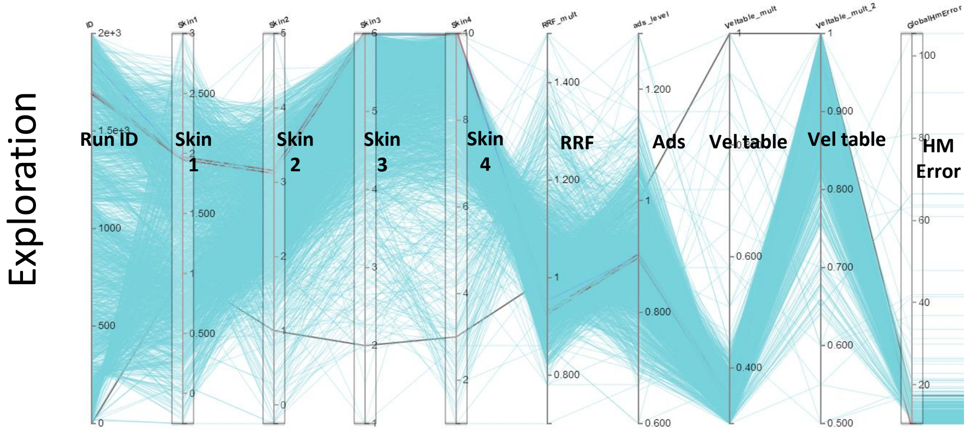



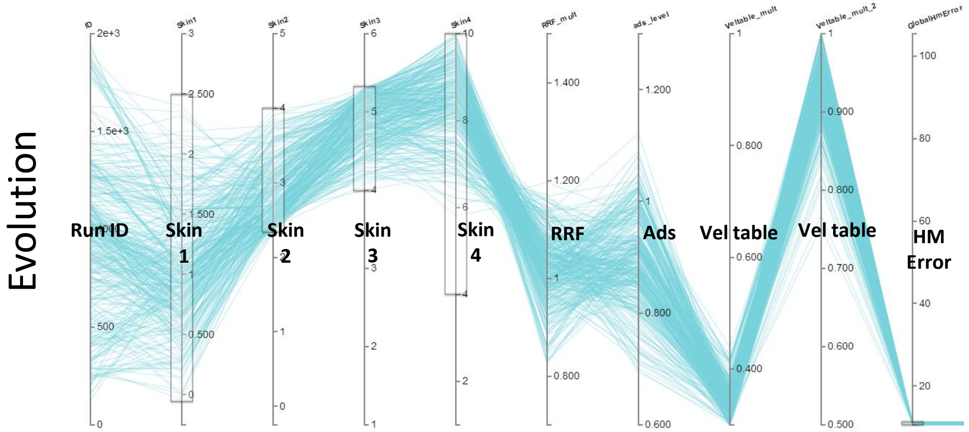

For more details on experimental work see (Masalmeh,et al, 2019).

# Assisted HM

Example of the exploration and evolution stages



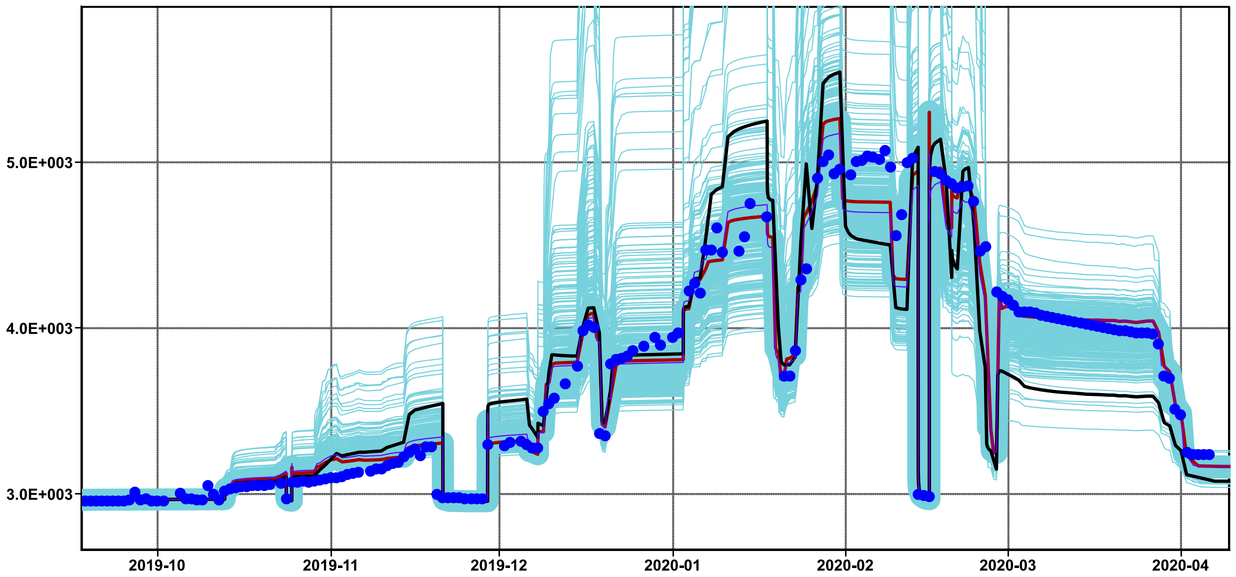

| ID | Skin1 | Skin2 | Skin3 | Skin4 | RRF_mult | ads_level | Veltable_mult | Veltable_mult... | GlobalHmError | HMError001 |
|---|---|---|---|---|---|---|---|---|---|---|
| 57 | 2.545 | 1.64 | 4.325 | 1.18 | 1.276 | 0.964 | 0.412 | 0.9125 | 22.802584 | 22.802584 |
| 58 | 2.935 | 1.98125 | 4.175 | 3.52 | 1.392 | 0.9395 | 0.349 | 1 | 19.09976 | 19.09976 |




| ID | Skin1 | Skin2 | Skin3 | Skin4 | RRF_mult | ads_level | Veltable_mult | Veltable_mult... | GlobalHmError | HMError001 |
|---|---|---|---|---|---|---|---|---|---|---|
| 962 | 1.1475 | 2.66375 | 4.55 | 7.75 | 1.068 | 0.8695 | 0.328 | 0.96 | 10.710032 | 10.710032 |
| 730 | 0.90375 | 3.03125 | 4.925 | 8.38 | 1.036 | 0.8555 | 0.328 | 0.96 | 10.710723 | 10.710723 |

**Iterative optimization history match method implemented to evaluate multiple parameters and possible scenarios.**

## WBHP HM Scenarios




***Good fit based on experimental data***

***No injectivity difference between pre-degraded solutions***

# Summary

- A novel polymer was developed and qualified for HTHS applications through laboratory studies
- Polymer injectivity was evaluated in the lab and showed that reservoir viscosity could be maintained even for pre-degraded solutions by concentration compensation
- A 760 day polymer injectivity well test was performed successfully
- PIT showed good injectivity and better than expected from lab experiments
- The need for pre-degradation was reduced in the field compared to the lab

# ¡THANKS!

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**ANNUAL EVENT**

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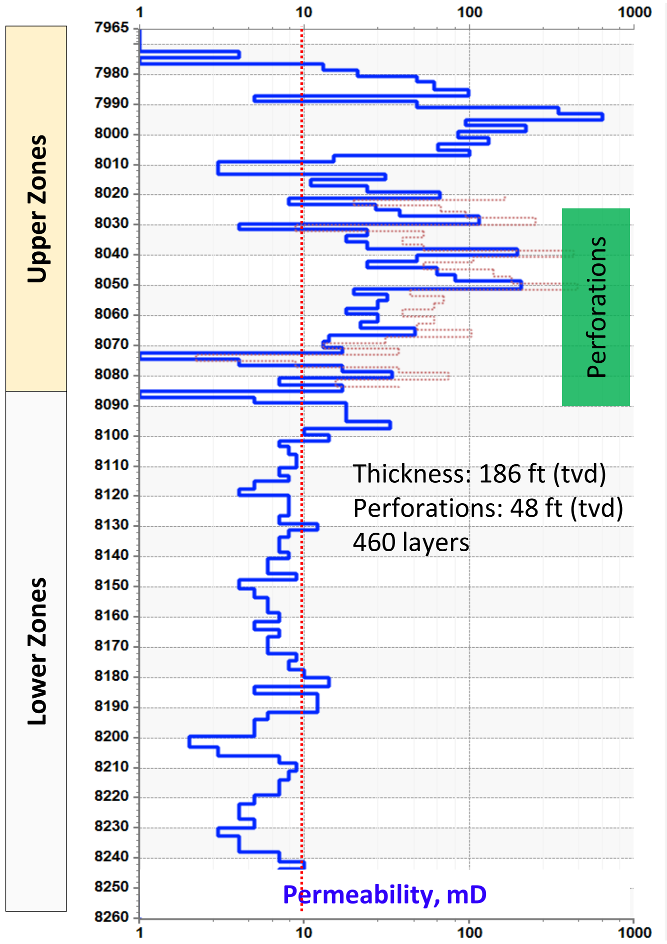
Enhanced Oil Recovery

Technology Collaboration Programme by iea

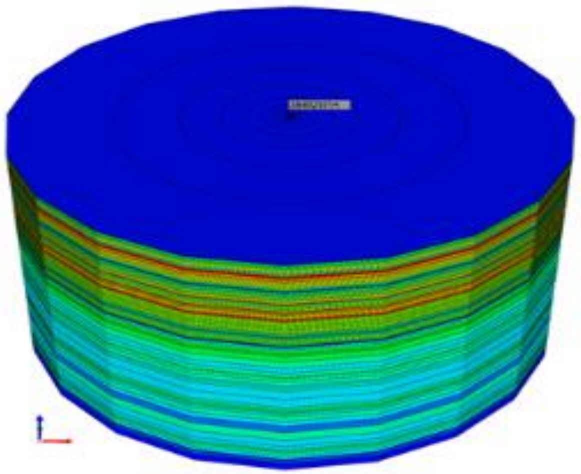
# Backup slides

# Injection Model

**Initial Grid From Well Logs**



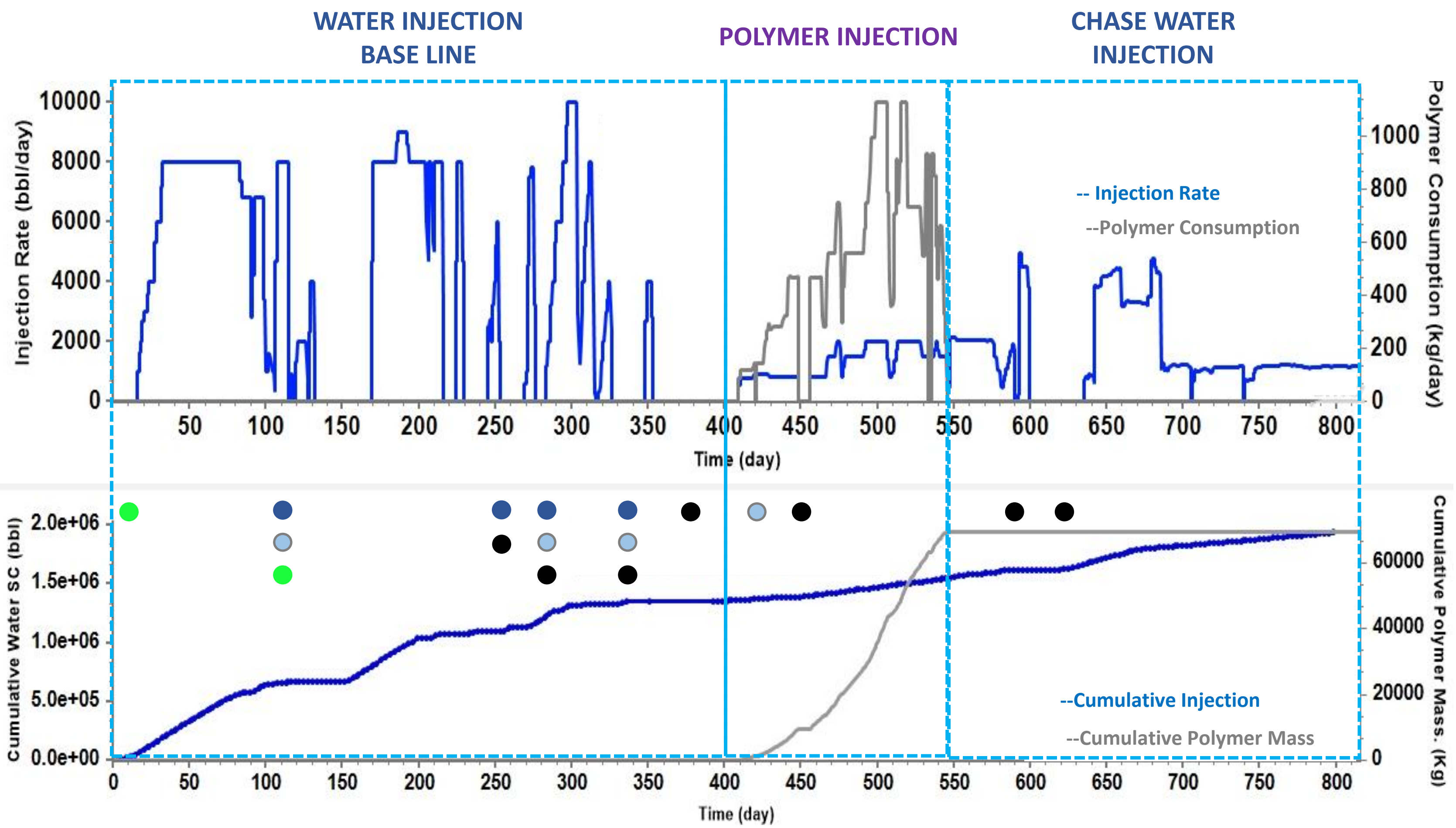

**Upscaled Radial Grid**



| | |
|---|---|
| **MODEL TYPE** | • BLACK OIL.<br>• SINGLE MEDIUM.<br>• ISOTHERMAL.<br>• NO GEOMECHANICS. |
| **GRID DIMENSIONS** | • 20 X 1 X 89. (2 – 11 f t)<br>• INNER RADIUS 0.3 FT OUTER RADIUS 3000 FT |
| **PVT** | • TEMP: 248F<br>• OIL VISCOSITY: 0.32 cP<br>• WATER VISCOSITY: 0.43 cP |

- Capture the expected exponentially decreasing velocity profile.
- Corroborate the impact of multiple Polymer parameters on Injectivity.

# Polymer Injectivity Well Test




**Water Injection Base Line**:

- **354 days / 1,4 Mbbl**

**Polymer Injection:**

- **138 days / 146 Mbbl / 68 ton**

**Chase Water Injection:**

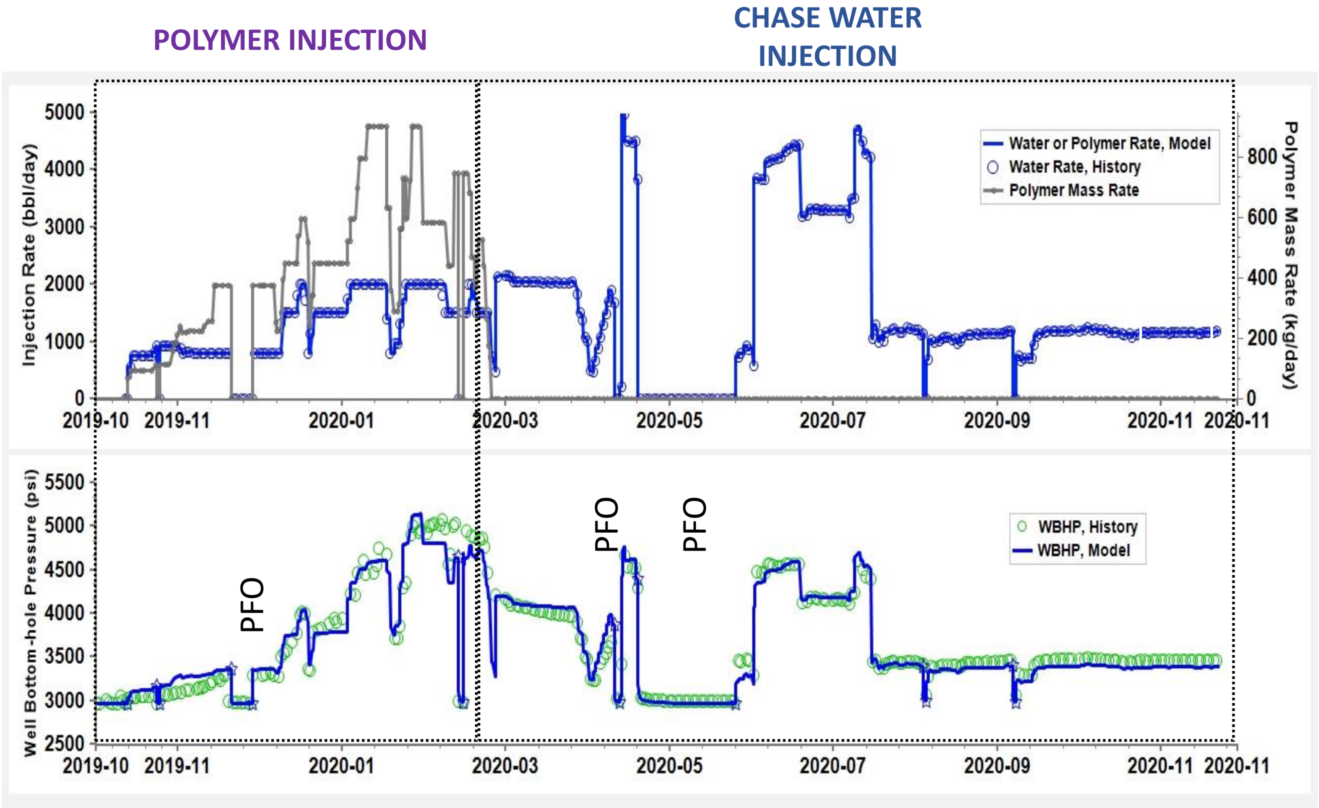
- **270 days / 380 Mbbl.**

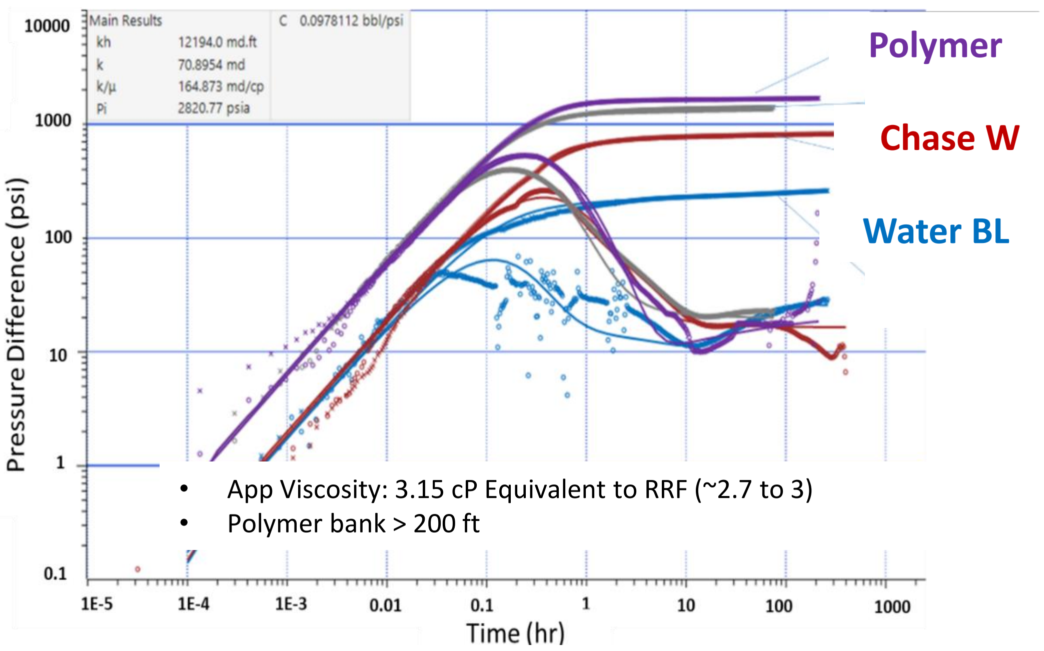
**PIT Monitoring Program**

- RST SRT PIT PFO
- Real-time pressure / temp downhole & surface gages.
- In-line and manual polymer viscosity.

For more details on PIT program see (Rachapudi, et al, 2020)

# Polymer Injection Well Test




- Good history match obtained using lab parameter ranges and consistent with anchor periods and PFOs interpretation.
- Based on both laboratory data and PIT interpretation, a Resistance Factor about 10 can be achieved using polymer concentrations between 1500 - 2000 ppm active.

- Injectivity Index (II) declined from ~13.0 bpd/ psi (WI baseline) to a minimum of 1.0 bpd/ psi (during Polymer injection) and it was stabilized at 2.6 bpd/ psi (during Chase Water).